DIRECT TESTIMONY OF
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ON BEHALF OF
SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND
SOUTHERN ALLIANCE FOR CLEAN ENERGY
DOCKET NO. 2020-2-E

INTRODUCTION

Q. Please state your name, business address, and employment.

A. My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, West 3 Peabody, MA 01960, and my email address is glander@skippingstone.com. I am President of Skipping Stone, LLC ("Skipping Stone").

Q. On whose behalf are you testifying?

A. The South Carolina Coastal Conservation League ("SCCCL") and the Southern Alliance for Clean Energy ("SACE").

Q. What is your educational and professional background?

A. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). From 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis. One of the many transactions I worked on for a potential purchaser client was SCANA's sale of Carolina Gas Transmission, now Dominion Energy Carolina Gas Transmission (DECGT).

Q. Have you filed testimony in regulatory proceedings previously?

A. I have filed testimony in several proceedings including FERC Docket No. RP04-251-000, which was an El Paso Natural Gas Company ("EPNG") proceeding regarding pathing and segmentation. In FERC Docket No. RP08-426-000 (also an EPNG proceeding), I sponsored answering and supplemental answering testimony. I also filed testimony in FERC Docket No. RP10-1398, the first fully litigated EPNG Rate case in more than three decades. In addition, I have filed testimony in Massachusetts Department of Public Utilities Case Nos. 13-157, 15-34, 15-48, and 15-39; Maine Public Utilities Commission Case No. 2014-00071; Virginia Corporation Commission Case Nos. PUR-2017-00051, PUR-2018-00065, and PUR-2019-00070; Missouri Public Service Case GR-2017-0215; GR-2017-0216; California Public Utilities Commission Cases 17-10-007 and 17-10-008 (Consolidated) Applications of San Diego Gas & Electric (U902M) and Southern California Gas Company (U 338-E) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019; South Carolina Public Service Commission Docket Nos. 2017-370-E; 2017-305-E; 2017-207-E, 2019-2-E, and 2019-3-E; New York Public Service Commission Docket Nos. Case 19-G-0066, Case-19-0309, and Case 19-0310; and FERC Docket No. ER18-1639. Please refer to Exhibit GML 1 for a full list of case names and docket numbers as well as my current CV.

SUMMARY

Q. What is the purpose of your testimony?

A. My testimony concerns how well the Company minimizes customer natural gas fuel costs while supplying reliable electricity to its retail customers. I find that in two distinct areas the Company has failed to reasonably minimize customer cost. First, DESC has failed to correctly allocate pipeline capacity fixed costs between its Gas and Electric Division. Second, DESC has signed two pipeline contracts—one with Transcontinental Gas Pipe Line (Transco) for the Southeastern Trail (SET) project and one with Mountain Valley Pipeline (MVP)—that are highly likely to impose unnecessary costs on ratepayers. I recommend the Commission take action to protect ratepayers from these expensive, needless contracts. Remedying the Company's failures should correctly allocate and reduce costs the Company may pass on to its customers.

Q. Can you walk us through what you will discuss in your testimony?

A. I first provide an overview of natural gas fuel markets. Next, I analyze how well DESC makes use of its existing pipeline contracts (load factor analysis) and discuss how fixed costs of these contracts are allocated between DESC's Electric and Gas Divisions. Then, I assess where DESC purchases its gas supplies and the pricing at those locations.

This underlies my assessment of whether the SET and MVP precedent agreements provide ratepayer value.

OVERVIEW

Q. Could you begin by providing a brief, high level, overview of natural gas fuel markets?

A. Yes. I think it's important to provide some background about natural gas fuel costs and how they are priced. The costs of delivering fuel to natural gas-fired power plants include two components: (1) the commodity price, which is the cost of the gas itself, and (2) the transportation cost. Together these components make up the "delivered" price of gas

The commodity price is determined by a variety of factors, the most important of which is the geographic diversity of natural gas production areas. The cost (price) of gas produced in one area of the country can, and often does, differ from the cost (price) of gas in a different production area.

The transportation cost is the cost of using a natural gas pipeline. Each pipeline is priced differently, depending on its size, location, age, and sometimes the distance between receipt and delivery locations. Another important but more recent factor is whether a particular service or contract is for an "incrementally priced" service of the pipeline.

Q. Please briefly explain what you mean by incrementally priced.

A. Incremental pricing refers to the rate a customer must pay to use capacity on expanded or new segments of pipeline – specifically, segments that did not exist prior to the mid to late 1990s (depending on the pipeline). In 1999 FERC formalized a policy requiring that pipeline owners, when building new line or installing compression to increase capacity for new customers, charge those new customers *all* costs of the new capacity and not pass any of such costs on to existing customers. The rate charged to those new customers is referred to as the "incremental rate."

The following examples show how this requirement plays out in practice. If the cost of new facilities needed to provide a new or additional service would yield rates that are lower than the existing rates on the pipeline for similar service, the pipeline is required to charge the existing (higher) rate to new customers (and existing customers with contracts for new capacity). On the other hand, if the costs needed to provide new or additional service would yield rates *higher* than existing rates, the pipeline must charge the new customer an incremental rate that recovers such project costs, thereby preventing those costs from being borne by customers not receiving the new or additional service.

When a company wants to contract for additional capacity on a fully-subscribed pipeline, the company has to pay for any required expansion. This generally means signing up for a service with an incremental rate. Because there have been many expansions, reversals, and extensions over the past ten or so years, there is more expensive newer capacity operating alongside lower cost "legacy capacity." This lower cost capacity provides (or is expected to provide) the same service on the pipelines with which DESC currently has contracts, but of course the price is lower.

Analysis of DESC Load Factor Utilization of Contracted Pipeline Capacity

Q. Which natural gas pipelines does DESC contract with for power generation at its plants?

A. DESC has contracted with two pipelines that connect directly to its plants: the Southern Natural Gas Company (Sonat) pipeline, and Dominion Energy Carolina Gas Transmission (DECGT) system. DESC's Aiken/Urquhart Plant is connected to the Sonat pipeline, while the rest of its power plants are connected to DECGT. DESC has additional contracts with Transco and Elba Express Company (Elba Express). While those pipelines are not connected directly to DESC's power plants, they can feed gas into Sonat and DECGT.

Q. What capacity does DESC currently hold on each of these pipelines?

A. At present, DESC's Electric Division holds 221,900 Dth per day (Dthd) of firm capacity on DECGT, the pipeline on which its holdings are greatest. DESC's Electric Division also holds 111,050 Dthd firm capacity on Sonat which is capable of delivering: a) 51,050 Dthd to both its Aiken/Urquhart plant and to DECGT at Aiken; and b) another 60,000 Dthd to DECGT at Port Wentworth. DESC also holds 61,500 Dthd of capacity on Elba Express which is capable of delivering to DECGT at Port Wentworth. Finally, DESC's Electric Division holds 40,000 Dth per day (Dthd) of firm capacity on Transco from its northern Leidy supply point to the Station 85 supply point in Alabama. The Transco capacity "path" encompasses delivery capability to DECGT in South Carolina.

Q. Did you perform any load factor-related analysis?

A. Yes. Load factor utilization is the percentage of contracted capacity that is actually utilized. Typically, load factor utilization can reach no more than 100%. However, my review discovered deliveries to the DECGT-connected power plants *exceeding* DESC's contracted capacity on 154 of 365 days, with a peak daily delivered quantity of 327,063 Dth (approximately 105,000 Dthd more than the Electric Division's contracted DECGT capacity level). Likewise, deliveries from Sonat and Transco also exceeded the Electric Division's contracted capacity on those two pipelines. This raises the question of where this excess capacity was sourced. In discovery, DESC disclosed that its Electric Division uses capacity held by its Gas Division when the Electric Division has scheduled more gas than its contracted level of capacity. DESC Response to CCL and SACE Data Request 3-7 b.

Q. Two part question: First, please explain how the Electric Division is able to use the Gas Division's capacity; and second, doesn't the Gas Division need the capacity that the Electric Division is using?

A. As to the first question, my understanding from prior DESC testimony is that one group of staff handles transportation scheduling for both the Electric and Gas Divisions. As a result, capacity held by the Gas Division can be scheduled to the Electric Division's gas-fired power plants when there is anticipated burn that could exceed the Electric Division's otherwise available capacity. As to the second question, the Gas Division does not need all of its capacity every day. Most of its demand is for meeting heating load on very cold days. When its heating load is low, the Gas Division has contracts for much more capacity than it needs. This unused contracted capacity becomes "contractually available capacity" to DESC's Electric Division.

Q. How much of the Gas Division's capacity did the Electric Division use during the Review Period for this case?

A. For DECGT, the Electric Division used 7,469,420 Dth of capacity held by the Gas Division in 2019. DESC Response to CCL & SACE Data Request 1-24. The sum of Sonat capacity used by DESC Electric Division in excess of its daily contract demand was 155,610 Dth[1]; and the sum of Transco capacity used by DESC Electric Division in excess of its daily contract demand was a substantial 3,887,086 Dth. The sum of the excess across all three pipelines was 11,512,116 Dth.

Q. Does that mean the Electric Division has insufficient capacity to meet its needs?

A. No. I reviewed the load factor utilization of the Electric Division's capacity (excluding its use of contractually available capacity held by the Gas Division) and found the following for 2019:

Sonat	39%
Elba	84%
Transco	98%
DECGT	88%

The above load factor utilization means that the "fit" between the Electric Division's contracted capacity and its use of that capacity is a good one. An 88% utilization (i.e., DECGT), while still less than 100%, is nevertheless very good. Likewise, the Elba Express (84%) and the Transco (98%) load factor utilizations of contractually subscribed capacity are very good. While the 39% load factor utilization of the Sonat capacity is low, the last increment of this capacity (60,000 Dthd) was recently obtained via the capacity release market, on a permanent basis. The right of first refusal at renewal time belongs to DESC. This represents attractively priced capacity that has substantial access

[1] This excess of contracted capacity use of Gas Division Sonat capacity appears to be all in advance of the Electric Division's acquisition of the 60,000 Dthd of Sonat capacity from SEMI in the capacity release market. This addition of 60,000 Dthd led to the apparent lower load factor. That said, the cost of this firm capacity relative to the cost of other firm capacity makes it attractive.

to competitive supplies and storage locations. This capacity can be used by DESC for as long as they are willing to pay maximum rates for that capacity[2].

Q. If the Electric Division is making good use of its existing contracts, why do you raise the issue of the Electric Division's use of the Gas Division's contractually available capacity?

I am not concerned about the practice itself, but rather about policy considerations related to how costs for that capacity are allocated between gas and electric ratepayers. As an operational matter, sharing this contractually available capacity between the Divisions makes a great deal of sense, and enables DESC to make higher overall load factor use of its pipeline capacity contracts. But from a policy perspective, it appears that the Electric Division does not compensate the Gas Division's ratepayers for the benefit they receive under these contracts. Rather, pursuant to a memorandum, when one Division uses the other Division's capacity, the using Division covers variable charges, commodity costs (i.e., the gas cost) and pipeline fuel charges, but does not contribute to any fixed costs associated with that capacity. That means that when the Electric Division makes use of the Gas Division's capacity, electric ratepayers receive nearly "free use" of contracted pipeline capacity paid for by the Gas Division's ratepayers. If the Electric Division instead had to buy the same daily capacity from DECGT, Sonat, or Transco, it would, at a minimum, have to pay interruptible rates. If the Electric Division bought the

[2] The maximum rates for this Sonat capacity are "legacy" rates and are less than incremental rates would be for new capacity.

same capacity in the short term capacity release market, it would have to pay market price.[3]

Q. What would you recommend that the Commission do?

A. I recommend that this Commission alter the current policy governing compensation by one Division for the use of another Division's contractually available capacity. The Commission should require that the compensation include covering fixed costs and not just variable costs.

Q. What would such a contribution mechanism look like?

A. A simple approach would be for DESC to internally charge the using Division (or credit the providing Division) at the 100% load factor equivalent of either: a) the rate applicable to the contract used, or b) the most recent incremental rate applicable to the same capacity. For legacy contracts, this would be the same as the pipelines' interruptible rates. For incrementally priced contracts, it would be the 100% load factor equivalent of those contracts' rates.[4] Note that all 100% load factor rates or their equivalents include variable charges of the pipeline. In either case, the revised policy should continue the current practice of covering gas commodity cost, pipeline usage cost and pipeline fuel cost.

Q. Do you have an estimate of what credit the Gas Division's ratepayers would receive for the Electric Division's use of its contractually available capacity in 2019?

[3] That market price could be higher or lower than the price for interruptible capacity from the pipeline. In the short term capacity release market there is no cap on capacity prices. The pipelines' prices for all services have price caps or maximum rates.

[4] To calculate a 100% load factor rate from a contract rate, the daily demand rate is added to the usage rate. The daily demand rate, if not presented in the pertinent tariff, is derived from the monthly demand rate by multiplying the monthly rate by 12 then dividing that result by 365.

A. Leaving aside the possible (if not likely) use that the Gas Division could have made of Electric Division contractually available capacity, and using 100% load factor "legacy" contract rates (i.e., IT rates), the total value that should be credited to Gas Division ratepayers is $3,481,183.77. Conversely, using the latest incremental rates for the same capacity yields $9,712,319.39 as the credit value. Without this crediting, Gas Division customers are forced unfairly to subsidize Electric Division customers.

Q. Which approach would you recommend the Commission use – the 100% load factor or incremental rates?

A. I would recommend incremental rates. From an economic and allocative efficiency point of view, using incremental rates would charge the using Division a rate that is a reasonable proxy for the unit cost of new capacity, should in fact such load need to be met with "new capacity" (as opposed to being opportunistically met by existing contractually available capacity). Note that "new capacity" would have to be paid for regardless of need or load factor usage and would likely cost more per unit that the most recent expansion used as a proxy. Nevertheless, such an allocation approach sends price and market signals more closely reflective of fully allocated costs, and it more accurately assigns costs across each Divisions' ratepayers. In addition, at the margin, it better communicates the value/cost of meeting the last increment of demand with energy from the existing system of gas infrastructure. Further, it enables all-in estimation of the cost of meeting the next increment of electrical demand with energy from future potential gas (or electric) infrastructure.

Q. How much incremental capacity would the Electric Division have to purchase elsewhere in order to have firm capacity equal to highest quantity provided by the Gas Division?

A. On DECGT the Electric Division would have had to purchase 105,173 Dthd and would have experienced a paltry 19% annual load factor utilization. On Transco, it would have had to purchase 81,647 Dthd and would have experienced an anemic 13% annual load factor utilization.[5] As such, I am not stating that the practice of sharing capacity is unwise; to the contrary, it is wise and prudent. Nevertheless, a new cost allocation policy appears warranted to ensure ratepayer fairness as well as to inform future infrastructure choices.

Q. Have you recommended such cost allocation process in any other fuel proceedings?

A. No. South Carolina is the first state in which I have testified where the utility is a combination gas and electric utility, where the electric division has utility-owned generation assets, and where the electric and gas divisions use contractually available capacity of each other. Given that, this is the first time I have testified on this specific issue.

Q. Do you recommend this allocation be made in this case?

A. I recommend that the data concerning daily volumetric use of contractually available capacity by one Division of the other's capacity be assembled by and for both the Electric and Gas Divisions for calendar 2019 and in the future. I also recommend that the Commission choose incremental pricing for internal cost allocation. I recommend the

[5] The effect of these low load factors is to increase the effective all-in cost to ratepayers of holding new capacity. For instance, a $0.60 per Dthd rate for capacity that is used at a 20% load factor has a cost in use of $3.00 per Dth actually used. ($0.60 divided by 20% equals $3.00)

Commission begin recognizing in Gas Division rates (as addressed in the upcoming Gas Division Case) the net benefit (or cost) to the Gas Division of these capacity transfers. Similarly, in the ensuing Electric Division fuel case, the Commission should integrate the outcome of the upcoming Gas Division allocation, plus allocation of actual 2020 net costs and January through March 2021 estimated costs. This will ensure that the rates of the two Divisions integrate the effects of mutual use of contractually available capacity by the other.

<u>Analysis of DESC'S SET and MVP Precedent Agreements</u>

Q. Before we get to any conclusions or recommendations you may have for the Commission with respect to these two precedent agreements, are the costs associated with either of these agreements in this docket?

A. Based upon the testimony I reviewed, it appears the MVP and SET contract costs are not at issue in this case because both are contracts for new capacity and neither project has yet been placed into service.

Q. Why then do you discuss the MVP and Transco SET contracts?

A. Because I believe Commission should look at the net effect on ratepayers of the capacity costs that DESC has signed up for under these two precedent agreements. The Commission should place DESC on notice that it may disallow some or all of those costs if they do not benefit ratepayers. The Commission should also note that DESC's recent purchases of 60,000 Dthd of Sonat capacity to DEGT at Port Wentworth and 61,500 Dthd of Elba Express capacity (also to DECGT at Port Wentworth) more than match DESC's 120,000 Dthd from Port Wentworth to Jasper (as well as some Columbia Area points).

As mentioned above, this Sonat capacity is priced no higher than legacy rates. Further, it is renewable by DESC for as long as DESC would be willing to pay maximum rates. As such, it should obviate the need to get new capacity.

Transco Southeastern Trail Precedent Agreement

Q. Please describe the SET agreement.

Q. This precedent agreement is for a [redacted] expansion project on the existing Transco system that would access supplies available in Transco's Zone 5[6] in Virginia (including supplies priced as Transco's Zone 5 North pricing point). Under the contract, DESC can make deliveries to DECGT, Elba Express, and further south. Notably, the capacity stretches from a receipt point in Transco's Zone 5 North (i.e., the Transco Pleasant Valley location) all the way down to Transco's Zone 3 in Louisiana (*i.e.*, Station 65).

Q. So what is the overall significance of this?

A. In short, the SET agreement enables DESC to buy gas at the Transco Zone 5 North pricing point and deliver it to DECGT, Elba Express, and potentially to Gulf Coast markets (including to LNG export shippers with capacity beginning at Station 65 on Transco for delivery to LNG export locations further west and south fed by Transco and other pipelines).

Q. Is gas produced in or around Pleasant Valley (*i.e.*, in or around Transco Station 185) in Northern Virginia?

A. No.

Q. Then why do you refer to this location as a supply area or receipt point?

[6] The capacity begins at the Pleasant Valley point of interconnection with the Dominion Cove Point pipeline at the far northern end of Transco's Zone 5 tariff Zone (and adjacent to Transco's Station 185) and is associated with the Transco Zone 5 North pricing location.

A. It is a supply area in the sense that parties can trade gas in /at locations associated with either or both of the Transco Zone 5 North points' and/or Transco Zone 5 Pooling points' pricing points. They can trade (i) gas from other pipelines that flows into Transco, (ii) gas within Transco that is moved from the North into or past Zone 5 to the South; or (iii) gas moved from the South into and past Zone 5 to the North.

Mountain Valley Pipeline Precedent Agreement

Q. With respect to the other precedent agreement, please detail the pipeline, the quantity of capacity, the supply area(s) accessed and where the subject capacity enables deliveries to be made.

A. The other precedent agreement is between DESC and the yet-to-be-in-service Mountain Valley Pipeline ("MVP"). It provides for [redacted] of capacity starting from the area of Southwestern Pennsylvania generally associated with the Dominion South Point pricing location and proceeding from there to Transco in the vicinity of Transco's Station 165 in Virginia (also proximate to the Transco Zone 5 "pooling point" and Transco Zone 5 pricing point). This capacity does not deliver to any DESC generating plants, nor would it deliver gas to DECGT or Elba Express. This capacity only delivers to Transco in Virginia.

Q. So, in other words, DESC could only use this capacity to deliver gas to Transco, and DESC would then have to use its Transco capacity (and other capacity) to actually get the gas to its generation fleet?

A. Correct.

Q. Could this capacity feed the capacity under the Transco SET project?

A. Yes. That would be how DESC would take the MVP gas on a firm basis to its facilities (i.e., after Transco delivers the gas to DECGT or Elba Express). In addition, because the Transco SET capacity reaches the Gulf Cost, the MVP gas could also be delivered there for Gulf Coast markets or for LNG export, as discussed above.

Q. How did you begin your analysis of these two agreements?

A. First, using data supplied by DESC in this case, I reviewed the supply locations from which DESC obtains and transports its gas under its current contracts. I then grouped these locations by their respective index or pricing points and pooling locations. This information is captured in **Figure 1** below.

Q. Before we move on, please define "index or pricing point" and "pooling location."

A. An "index point" or "pricing point" is a location that has a published price. These may include receipt and/or delivery locations that are considered by the pipeline as the "same" from a capacity perspective. A "pooling location," by contrast, is a virtual location where parties with capacity in the zone of the pooling point that are buying or selling gas in that particular pipeline zone can engage in trades.

Q. You say a pooling location is "virtual." How does that work?

A. Parties with supply in the areas specified by the pipeline tell the pipeline that they want to sell a portion of that supply to a buyer. In turn the buyer tells the pipeline that they wish to buy the same amount from the seller. The pipeline then transfers this amount from the selling party to the buying party. Once that happens, the buying party either sells the gas again to another party at the pool, or puts the gas onto a transportation contract in order to move it to another location on the pipeline.

Q. What does Figure 1 show?

A. **Figure 1** below shows all the distinct supply points (receipt locations) at which DESC bought gas for electric generation during the full year period of January 1, 2019 through December 31, 2019, and the pricing zone or locations associated with such purchase point:

Figure 1

Receipt location (a)	Pricing Zone-Loc
604000	Sonat Zone 0
606500	Sonat Zone 1
606700	Sonat Zone 1
608500	Sonat Zone 1
AIKEN	Sonat Zone 3
ELBA	DECGT Zone 2
Elba Express	Elba Express
Elba Express(MFTEEC)	Elba Express
ELBA TAILGAT	Sonat Zone 3
ELBA-IT	Elba Express
GROVER	Transco Zn 5 South
PETAL STORAGE	Sonat Zone 3
Pool 10176	Sonat Zone 3
POOL100176	Sonat Zone 3
PORT WENTWOR	DECGT Zone 2
Port Wentworth	Elba Express
PtWntwth	Sonat Zone 3
ROSEHILL	Sonat Zone 3
SEMI SNG Z3	Sonat Zone 3
SNG POOL	Sonat Pool
SNG Z3 POOL	Sonat Zone 3
STATION 85	Sta 85 - Zone 4
TRANSC LEIDY	Leidy - Zone 6
ZONE 4	Sta 85 - Zone 4
ZONE 5	Zone 5

Sources: DESC Response to CCL & SACE Attachment 1-25 a. b.; DESC Responses to CCL & SACE 4-1 & 4-2; Analysis Skipping Stone.

Q. It looks like multiple supply points share a pooling location. Is that relevant?

A. Yes. As discussed above, gas procured from supply points within the same capacity area of a pipeline are within the same pricing zone/pricing point (or location). In **Figure 2**, I calculated the total amount of gas supply and the annual average price of gas that DESC gets from each index point:

Figure 2

Pipeline	Pricing Zone-Loc	2019 Volume (Dth)	Pctg of Supply	Average Price ($/Dth)
Sonat	Sonat Pool	[redacted]	[redacted]	[redacted]
DECGT	Transco Zn 5 South	[redacted]	[redacted]	[redacted]
Sonat	Sonat Zone 3	[redacted]	[redacted]	[redacted]
Transco	Leidy - Zone 6	[redacted]	[redacted]	[redacted]
Transco	Sta 85 - Zone 4	[redacted]	[redacted]	[redacted]
Elba Express	Elba Express	[redacted]	[redacted]	[redacted]
Transco	Zone 5	[redacted]	[redacted]	[redacted]
DECGT	DECGT Zone 2	[redacted]	[redacted]	[redacted]
Sonat	Sonat Zone 1	[redacted]	[redacted]	[redacted]
Sonat	Sonat Zone 0	[redacted]	[redacted]	[redacted]
	Total	[redacted]	[redacted]	[redacted]

DESC Response to CCL & SACE Attachment 1-25 a. b.; DESC Responses to CCL & SACE 4-1 & 4-2; Analysis Skipping Stone.

As **Figure 2** shows, DESC obtains [redacted] of its natural gas supply from four Transco pricing zones/pricing points. About [redacted] of DESC's supply is delivered into DECGT through locations whose pricing point is tied to the **Transco Zone 5 South** pricing zone; about [redacted] is tied to **Transco Leidy** (which is in Zone 6, where the Marcellus gas that is connected to Transco is produced); about 9% is tied to **Transco Zone 4** (i.e., Station 85); and about [redacted] is tied to **Transco Zone 5**. An additional [redacted] of DESC's natural gas supply was purchased at locations tied to a Sonat pricing point. Finally, [redacted] was purchased into Elba Express.[7]

Q. Above, you calculated that [redacted] of DESC's supply was purchased at Transco pricing locations two of which have Zone 5 in their identifier. And in discussing SET you mentioned Zone 5 North, which is not in Figure 1. In this regard, please discuss what distinguishes Zone 5 North, Zone 5 and Zone 5 South.

A**.** Zone 5 North refers to pricing locations where gas is purchased into Transco from other pipelines delivering into Transco in Northern Virginia (or sold out of Transco in the same vicinity). Transco Zone 5 generally refers to transactions that occur at the Transco Zone 5 pooling point or in the vicinity of Station 165 in Southern Virginia. Transco Zone 5 South refers to transactions that occur at locations in North and South Carolina. Since the recent reversals and expansions of Transco, the supply and demand balance (and therefore price) can vary among these vicinities.

As to the absence of Transco Zone 5 North in the list of locations where DESC purchased supply, it is possible that DESC bought supply there as DESC identified a small quantity of gas as Zone 5 without any other qualifier.

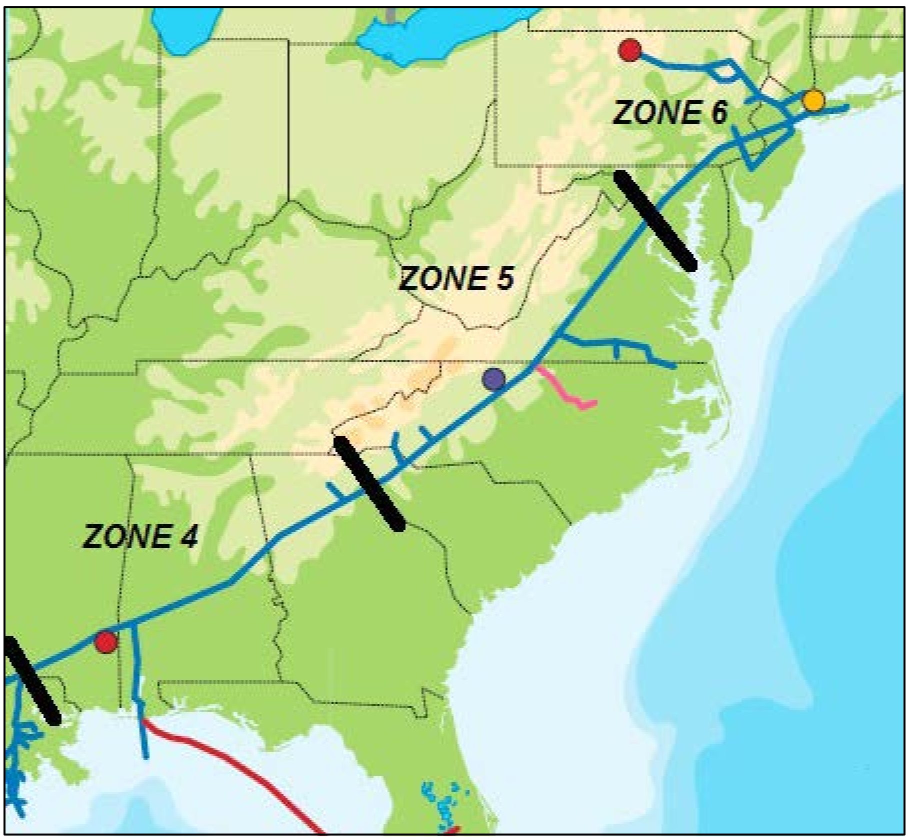
Q. In addition to the three Transco Zone 5 pricing locations, you mention Transco Zone 6, and Transco Zone 4. What do those refer to?

A. The Transco pipeline is the main artery of all natural gas on the East Coast. It runs from the Gulf of Mexico to New York. The map at **Figure 3** shows the Transco pipeline

[7] Elba Express is connected to Transco at both a Transco Zone 4 and a Transco Zone 5 location; thereby enabling gas to reflect Zone 4 or Zone 5 pricing depending on the direction from which the gas was coming. Elba Express can also receive gas from and deliver gas to Sonat. Finally, Elba Express is connected to the Elba Island LNG export/Import location and can both receive from and deliver to the LNG facility. All volume and price data was compiled from DESC Responses to CCL & SACE Attachment 1-25 a. b.; DESC Responses to CCL & SACE 4-1 & 4-2. In addition, a small [redacted] was purchased in DECGT Zone 2.

and the relevant zones I'm discussing. Zone 6 is the Maryland to New York and Pennsylvania market area as well as the Marcellus supply area in Pennsylvania. Zone 4 is south of Zone 5 and is a supply area where gas comes into Transco from points further south on Transco as well as pipelines that come from the west and deliver to Transco. Transco's Station 85 is the Transco Zone 4 pooling point.

Figure 3



Source: http://www.1line.williams.com/Transco/files/presentations/2012ExecCustMeet.pdf (Zone labels and dividing lines added by Skipping Stone for clarity).

Q. How much supply does DESC procure from each of the four Transco pricing points listed in Figure 2?

A. Of the [redacted] of supply made up of Transco-sourced supplies, the largest is the [redacted] of gas bought by DESC out of Transco delivered into DECGT. This occurs at what

DESC calls the "Grover" interconnect. DECGT's interconnects with Transco, including Grover, are all in Transco Zone 5 South. Next largest is Transco Leidy (Zone 6), which makes up [redacted] of DESC's total supply. Then there is Transco Station 85, which is in Transco Zone 4 and accounts for nearly [redacted] of DESC's supply. Lastly by volume is the [redacted] that DESC listed as "Zone 5" supply in its data responses to CCL and SACE.

Q. Does the average pricing at these four Transco pricing points differ significantly?

A. Historically, they were very different. But as more and more expansions on Transco go into effect, the annual average prices at these four locations have begun to converge.

I'll review each pricing point in order from lowest average price to highest. First, DESC's fuel supply from Zone 6 (the northernmost zone) had the lowest average cost of its Transco supplies, with an annual average of [redacted] per Dth. This reflects the abundance of supply here relative to the pipeline takeaway capacity.[8] Generally, the Marcellus is priced below the pricing benchmark known as the Henry Hub.

The next lowest average price was the [redacted] of DESC's total supply that was bought at prices tied to Transco Station 85 in Zone 4 (the southernmost zone where DESC purchased supplies). These supplies averaged [redacted] per Dth in 2019. Since 2016, Transco Station 85 prices have been annually averaging under the Henry Hub by a few cents.

Next lowest priced, and the largest single Transco source for DESC, is the [redacted] of total supplies bought by DESC and delivered into DECGT in Zone 5 South. This Transco

[8] When there is more supply connected to a line than can get into the line, prices are bid down until the supply and capacity are balanced. Likewise when there is more demand than the capacity to deliver gas to meet that demand prices are bid up until demand and capacity are balanced.

to DECGT interconnect is the "Grover" location; it carried an average price in 2019 of [redacted] per Dth.

Finally, the highest priced (and lowest volume) of DESC's Transco supplies was the [redacted] of total volume bought at what DESC terms the "Zone 5" location. This location carried an annual average price of [redacted] per Dth.

Q. With respect to Transco annual average prices and volumes and their respective pricing zones, what observations or conclusions have you drawn from the data in Figures 1 and 2?

First, the least expensive supplies are those that come into Transco as transacted by DESC (and others) at Transco's northernmost (Zone 6) and southerly supply areas. Second, as I discuss further below, pricing services and DESC's own reported purchases show that supplies transacted at Zone 5 South locations are now often less expensive than the reported prices for other Zone 5 locations.

Q. Please explain Figure 4.

A. **Figure 4** below shows the average seasonal prices at the index points where DESC currently purchases about [redacted][9] of its supply for electric generation, along with pricing at two other index points for reference. I have included pricing at Zone 5 North because that would be the northernmost pricing location that the SET project would access (i.e., the beginning of the SET capacity path). In addition, I have included the pricing at Dominion South Point because that would be the pricing location where the MVP capacity path originates.

[9] This [redacted] is the total for the supplies purchased at Transco pricing points – the [redacted] -- and the [redacted] purchased a Sonat pricing locations.

Figure 4

Seasonal Periods	Days in Period	Southern Natural Avg Price	Transco Zone 4 Avg Price	Transco Zone 5 North Avg Price	Transco Zone 5 South Avg Price	Dominion South Avg Price	Transco -Leidy Line Avg Price
Shoulders 2017	122	2.960	2.960	2.960	3.030	1.740	1.715
Shoulders 2018	122	2.835	2.855	2.955	2.970	2.350	2.080
Shoulders 2019	122	2.485	2.488	2.483	2.535	2.055	1.978
Winter 2017/2018	151	2.760	2.780	3.075	3.095	2.425	2.375
Winter 2018/2019	151	2.870	2.900	3.185	3.200	2.735	2.785
Winter 2019/2020, thru Dec 31	151	2.285	2.330	2.425	2.440	1.890	1.865
Summer 2017	92	2.870	2.900	2.895	2.980	1.850	1.810
Summer 2018	92	2.870	2.890	3.000	2.990	2.430	2.350
Summer 2019	92	2.203	2.250	2.305	2.300	1.928	1.900

Source: Natural Gas Intelligence; Analysis Skipping Stone.

Q. What do we learn from this table?

A. This table shows three important facts relevant to understanding the differences between current and potentially future pricing points available to DESC. First, in any given year, the prices in Zone 5 North do not often substantially differ from the prices in Zone 5 South (shown in the lightly shaded cells). Second, when they do differ, sometimes Transco Zone 5 North is lower priced than Transco Zone 5 South. While the reverse can also be true, in recent years Transco Zone 5 South's price is trending to be the same or lower priced than Transco Zone 5 North during the consistently high electric demand summer periods.

Q. You have identified Transco's Grover interconnect with DECGT as within Transco Zone 5 South. What are examples of Transco Zone 5 North supply locations?

A. One is the interconnect with Dominion's Cove Point LNG Pipeline, another is the interconnect with Dominion Transmission, and a third is with Columbia Gas Transmission.

Q. Why do you note the price differences between Transco Zone 5 North and Transco Zone 5 South?

A. DESC largely depends upon the DECGT pipeline system to deliver gas to its gas fleet. To connect the DCEGT pipeline to gas supply areas, DESC uses (or gets gas from others using) the Transco mainline, which runs all the way from the Gulf of Mexico to Pennsylvania and New York/New Jersey.[10] DESC can currently access Transco Zone 5 North supplies only if it has capacity on Transco to receive gas at (or north of) Transco Zone 5 North locations and deliver it into DECGT in Transco Zone 5 South for onward transportation to its gas-fired plants. Showing these two allows comparisons between prices that DESC can currently access at Transco Zone 5 South versus what DESC might, in the future, access in Zone 5 North with the SET capacity.

Q. How could DESC currently get gas from Transco Zone 5 North to its gas plants?

A. One way for DESC to get gas from Transco Zone 5 North to Transco Zone 5 South is to use its Leidy (Zone 6) to DECGT (Zone 5 South) contract. However, this would mean that DESC could not use that same capacity to buy Zone 6 Marcellus gas, which is generally cheaper than Zone 5 North supplies.

Thus, DESC also purchases supply from *other* Transco contract holders who sell gas to DESC out of Transco and into DECGT in Transco Zone 5 South. As discussed above, approximately [redacted] of DESC's supply comes from purchases at the Grover interconnect between Transco and DECGT. The Transco contract holders selling to

[10] Gas also comes from Sonat to DESC's Aiken/Urquhart plant and into DECGT to serve other of DESC's Plants. Sonat has facilities from far-eastern Texas to coastal Georgia and northern Florida.

DESC have access to supplies from other pipelines all along their Transco routes that bring gas from various production areas to Transco.

Q. Why is it important to discuss Transco Zone 5 North, its pricing, and access to capacity from there to DECGT?

A. As I discuss below, it relates to future potential costs to ratepayers associated with a Transco capacity contract from Zone 5 North past DECGT (in Zone 5 South) to Station 65 in Louisiana, which is in Transco Zone 3.

Q. Does Transco connect directly to any of DESC's plants?

A. No. At present, DESC's Electric Division holds 40,000 Dth per day of firm capacity on Transco from Leidy to Station 85 in Alabama. The interconnect with DECGT is in between these two points. While the "primary" receipt and delivery points for this capacity are Leidy and Station 85, respectively, DESC may likewise take gas out at Grover because it is within the primary path of the capacity. This means those deliveries are accorded the highest secondary firm priority on Transco. This is the same priority accorded other shippers delivering to DESC the [redacted] of supply that DESC buys at Grover.

Q. What other contracted capacity does DESC's Electric Division hold?

A. It holds firm capacity (111,050 Dthd) on Sonat, which is capable of delivering 51,050 Dthd to both its Aiken, SC plant (Urquhart) and to DECGT at Aiken; plus another 60,000 Dthd to DECGT at Port Wentworth. The Electric Division also holds 61,500 Dthd of firm capacity on Elba Express, which delivers to DECGT at Port Wentworth. Finally, the Electric Division has firm capacity on DECGT totaling 221,900 Dthd, its greatest capacity reserve of all.

Q. How does DESC's Electric Division capacity on the interstate pipelines feeding DECGT compare with its capacity on the DECGT system in South Carolina?

A. In-state DECGT capacity of the DESC Electric Division is 221,900 Dthd, while the Division's feeder capacity to DECGT (out-of-state) is 212,550 Dthd. This implies 95%+ "firm to firm match-up".[11] By this I mean the match between the capacity directly connected to the utility's generating stations and the upstream feeder lines needed to access producing regions. A shipper will often (but certainly not always) contract for firm capacity on feeder lines connected to producing regions in order to control access to supply. Here, there is an almost perfect match of direct connected capacity (i.e., DECGT capacity) to feeder capacity (i.e., Sonat, Transco and Elba Express), which is better than most generators have.

Q. Why do you discuss both where DESC buys its gas for electric generation from and its load factor utilization of pipeline capacity?

A. The reason this is important is because DESC has two precedent agreements that, together, commit DESC (and potentially its ratepayers) to an additional [redacted] of firm capacity. Of this [redacted] only [redacted] would actually be delivered to DECGT by Transco for use by DESC at its plants.

Q. Earlier in Figure 2 you showed that [redacted] of DESC's purchases were made at the Transco/DECGT interconnect that DESC calls "Grover" (the pricing point referred to as Transco Zone 5 South); won't that [redacted] be supplied by gas through the [redacted] contract with Transco instead?

[11] While the Elba Express capacity does not connect to natural gas production areas the way Transco and Sonat do; Elba Express does connect to the Elba Island LNG facility which retains all of its LNG storage and LNG re-gasification capability.

A. I analyzed the pattern of purchases at Grover off of Transco. I found that even if DESC had a contract for [redacted] and used that contract instead of buying gas delivered to DECGT at Grover, the contract would only have been used at a 41% load factor. And there would still have been 66 days in 2019 when DESC would have to buy gas delivered to Grover. This means that the [redacted] contract would not meet total needs and would be relatively under-utilized. DESC's Electric Division would be paying for 59% of capacity that went unused for electric generation.

Q. Would DESC save money buying gas and transporting it under the future Transco SET contract versus buying the gas at Grover?

A. Based upon my analysis, no.

Q. Before you get into the detail on this analysis, please explain at a high level what you mean.

A. A utility's job is to provide reliable service at the lowest reasonable cost. But lowest reasonable cost does not mean absolute lowest cost.

Q. Why not?

A. Well, for one thing, as discussed earlier, gas prices vary at different supply sources. Not only do they vary among themselves, they differ in time. *Location A* may be lower cost than *Location B* today, but the inverse could be true tomorrow.

Q. So it's impossible to always know which location will have the cheapest gas?

A. Correct. Not only that, but to the extent *Location B* has cheaper commodity prices tomorrow, a utility can take advantage only to the extent that it can get the purchased gas to where it is needed. This is where firm pipeline transportation contracts come in.

Q. And "firm pipeline transportation contracts" are ones that utilities pay for year-round, regardless of how much they use them?

A. Correct. Think of it as a hedge. There can be value to the utility, and by extension the ratepayer, in being able to shift purchases from one supply location to another. To do that, utilities need multiple transportation contracts. In DESC's case, this means having feeder pipeline contracts.

Q. So utilities have multiple contracts on multiple pipelines to ensure they can reach the lowest cost gas at any given time?

A. Yes.

Q. Is there a limit on how many contracts a utility should have?

A. Utilities differ, so there is no uniform number. However, I believe a utility should add new pipeline transportation contracts only to the extent those new contracts are needed to meet reasonable projections of demand *and* only where they provide ratepayer value.

Q. So, turning to the two contracts, are you saying they do not provide ratepayer value?

A. Having reviewed the likely gas commodity savings under these contracts and the likely fixed transportation costs they would impose, and after considering the "all in cost" and supply reliability benefit, I conclude that these pipeline contracts: (1) will not save ratepayers money, (2) offer *de minimus* – if any – supply reliability benefit, and (3) provide insufficient hedge value.

Q. Before we get to any conclusions or recommendations you may have for the Commission with respect to these two precedent agreements, are the costs associated with either of these agreements in the current Fuel cost case?

A. Based upon the testimony I reviewed, neither the MVP nor SET contracts' costs are at issue in this case because both are for new capacity and neither project has been placed into service.

Q. Why then do you discuss the MVP and Transco SET contracts?

A. Because the Commission should proactively assess the net effect on ratepayers of the costs associated with these two precedent agreements and place DESC on notice that the Commission could disallow some or all of any net costs.

Q. What would be the impact on ratepayers from these two potential future contracts?

A. The Transco SET project, as I stated above, is for [redacted]. The contract only connects DESC to a point in northern Zone 5 of Transco (the Transco Zone 5 North pricing point) [12] at a cost of [redacted] per Dth per day reservation charge. This Transco SET capacity will cost [redacted] per year. In addition, paying at least [redacted] on MVP (which connects to the Dominion South Point regional pricing) to Transco in Virginia raises the average price for connecting to this supply area by about an additional [redacted] per year. The total cost between the two is therefore [redacted] per year. Thus, between these two contracts, consumer fixed costs could be (if the Commission allows recovery) at least [redacted] per year higher than they are today, before any gas is purchased.

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[12] The primary receipt point on the contract, as stated above is Pleasant Valley. That said, all points between the primary receipt point and the Primary delivery Point (in Louisiana) are available on a secondary capacity basis.

Q. How long are these two contracts?

A. The Transco SET contract is for fifteen years from commencement of service and the MVP contract is for twenty years from commencement of service.

Q. Okay, but what if the gas is cheaper at the locations accessed by those contracts; wouldn't that be a benefit to DESC ratepayers?

A. To determine whether DESC ratepayers would benefit from accessing supplies at Dominion South Point prices versus Transco Zone 5 South, I analyzed the amount of gas purchased in Transco Zone 5 South which then went to plants. Based upon data supplied by DESC in discovery, I can reasonably conclude that DESC could utilize all of the [redacted] of Transco SET capacity on just 28 out of 365 days. Overall, its use of the SET capacity (based upon 2019 data) would be at only a 41% load factor. In addition, I can reasonably conclude that DESC could fully utilize the capacity on MVP that feeds Transco on 128 days out of 365 and that its load factor usage (again based upon 2019 data) would be 63%.[13]

Q. Doesn't the analysis stop there?

A. Absolutely not. Just because you ***<u>can</u>*** use something doesn't mean you should. The question is, and should be, "does having this capacity provide value to DESC ratepayers?"

Q. Does it?

A. No. Bear in mind that when using natural gas, a utility must pay both for the gas itself (the commodity price) and the costs of reserving transport capacity plus the variable cost of transporting the gas to its endpoint (i.e., both variable and fixed). Commodity

[13] This differs from my 2019 assessment, where I factored in DESC's Sonat deliveries to Urqhart as displaceable by Transco Zone 5 South supplies; this was an assumption DESC disputed.

prices vary among supply areas, but transportation costs may also vary among pipelines. A utility cannot simply look at which supply area has the lowest commodity price; it must look at the total cost, which necessarily includes transportation costs.

Q. So what you're saying is that, "all-in," it may not actually be cheaper to buy gas from *Point A* instead of *Point B*, if the costs of reserving and transporting the gas from *Point A* outweigh the commodity price savings?

A. Correct.

Q. Did you do that analysis here?

A. I did. I analyzed Natural Gas Intelligence (NGI)[14] spot pricing at locations pertinent to DESC's past purchasing practices. I evaluated how displacing purchases at those locations with new contracts would change supply costs. In the first table below I estimate the net value to ratepayers for the three periods of 2017, 2018 and 2019 had the MVP contract [redacted] of the Transco SET contract [redacted] been in place. I reviewed the SET contract in two parts because one part corresponds to the MVP contract with the balance able to access the Zone 5 North locations.

[14] NGI publishes daily spot prices at more than 100 North American pricing points.

Figure 6

Per Dth Value of buying Dom South vs Listed Pricing Points-->	Days in Periods	Southern Natural	Transco Zone 5 North	Transco Zone 5 South	[redacted]
Shoulders 2017	122	1.220	1.220	1.290	
Shoulders 2018	122	0.485	0.605	0.620	
Shoulders 2019	122	0.430	0.428	0.485	
Winter 2017/2018	151	0.335	0.650	0.670	
Winter 2018/2019	151	0.135	0.450	0.465	
Winter 2019/2020 thru Dec 31	151	0.395	0.535	0.550	
Summer 2017	92	1.020	1.045	1.130	
Summer 2018	92	0.440	0.570	0.560	
Summer 2019	92	0.273	0.375	0.385	
Totals for 2017 Prices					
Totals for 2018 Prices					
Totals for 2019 Prices					

Source: NGI for Prices, DESC Response to CCL & SACE 1-2; and Analysis Skipping Stone

Q. Please explain what is in this table/Figure 6.

A. This table breaks the years 2017, 2018 and 2019 into natural gas pricing seasons. It first displays the shoulder months of April, May, September and October (totaling 122 days). Next, it displays the winter periods of November through March of the next year (a period of 151 days). Then it displays the summer pricing period of June, July and August (92 days).

Q. Before you continue, why did you break these periods out?

A. Because the advantage of access to Dominion South Point and its supply prices varies by season. Winter is less advantageous than either the summer or shoulder periods for the supplies from Transco Zone 5 South (or Sonat) that the Dominion South Point supplies would displace.

Q. Please continue with your explanation of the table.

A. The table also presents the positive savings on gas cost (without considering transportation cost) that purchasing at Dominion South Point *would have produced* versus the gas cost of purchases associated with Sonat, Transco Zone 5 North, or Transco Zone 5 South.

Q. What did you do next?

A. Next I calculated the fixed transportation cost, which is the cost of reserving the capacity as set forth in the precedent agreements. The table presents the mathematical "net value" of this arrangement where transportation costs are subtracted from gas cost savings.

Q. And what does it conclude?

A. In order to have reaped gas cost savings, money would have to have been spent on the capacity to access those cheaper supplies. As one can readily see in the table above, whatever money may have been saved in gas commodity purchases would have been lost in increased transportation costs. There would have been no net value to ratepayers in 2017, 2018 or 2019 under the proposed arrangements. There would instead have been a loss (increase in ratepayer costs). The net loss in 2019 would have the worst overall.

Q. In each season except the winter of 2019, the net loss in 2019 is greater than the net loss in both of 2017 and 2018. Why?

A. In general, the price differential between different supply areas is collapsing. And while the net loss in winter 2019 was 10% less than 2018, the overall loss on an annual basis was 10% greater than 2018 and 250% greater than that of 2017.

Q. What does that mean?

A. It means that, generally speaking, gas commodity costs at pricing locations are converging throughout the country.

Q. Why is that?

A. Historically, supply areas that had insufficient pipeline infrastructure struggled to get their gas to markets. As such, those supply areas sold gas at a discount.

Q. Is that no longer the case?

A. Less and less so.

Q. Why?

A. Over the past decade or so, many pipeline companies have built new lines that connect supply areas to markets. As a result, the capacity constraints that caused producers to sell at a discount are shrinking, and prices are rebounding. In the vernacular, "basis" is collapsing.[15]

Q. Before proceeding to discuss the other Precedent Agreement; is there anything else you want to say about the MVP Precedent Agreement?

Q. A. Yes. [redacted] Recent

[15] "Basis" is simply the difference in gas price at two locations. In the above table, the positive numbers under Sonat and the Transco locations represents the "basis" differential between those locations and Dominion South Point. A positive value means that one would save that amount on gas costs buying at Dominion South Point versus the noted locations.

[16] See DESC Confidential Response to CCL & SACE 5-1 a., b., c., and d.

announcements by the MVP project sponsor (EQM) indicate that the final cost of MVP may reach $5.5 billion (up $2 billion from its original cost estimate). I do not know DESC's proportionate share of this increase, as may be reflected in its rates. However, in my experience it is usually greater than zero, and in many cases it is also capped at a stated rate. Even if DESC's rate does not increase as a result of the increased cost of constructing MVP, calculations I performed show that [redacted] I will return to this [redacted] when I recommend how this Commission can mitigate the effect of the MVP contract on DESC ratepayers.

Q. OK, what about the "value" of the other part of the Transco SET agreement?

A. In the table below I show the difference in value between buying at Transco Zone 5 North versus buying either at Transco Zone 5 South or Sonat.

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[17] [redacted]

Figure 7

Per Dth Value of buying At Listed Pricing Points Vs Transco Zone 5 South--->	Days in Periods	Southern Natural	Transco Zone 5 North	[redacted]
Shoulders 2017	122	0.070	0.070	
Shoulders 2018	122	0.135	0.015	
Shoulders 2019	122	0.055	0.058	
Winter 2017/2018	151	0.335	0.020	
Winter 2018/2019	151	0.330	0.015	
Winter 2019/2020 thru Dec 31	151	0.155	0.015	
Summer 2017	92	0.110	0.085	
Summer 2018	92	0.120	(0.010)	
Summer 2019	92	0.113	0.010	
Totals for 2017 Prices				
Totals for 2018 Prices				
Totals for 2019 Prices				

Source: NGI for Prices, DESC Response to CCL & SACE 1-2; and Analysis Skipping Stone

Q. Please explain what is in this table/Figure 7.

A. This table shows that while the Transco SET capacity can access the relatively cheaper supplies (in winter and shoulder periods, but not in the summer periods that are DESC's peak gas consumption periods) available at the Transco Zone 5 North pricing point, the net "value" to ratepayers would have been negative. In short, here too the transport costs associated with access to the cheaper gas would have eclipsed the commodity price savings.

Q. So what are the results here?

A. The total net loss to ratepayers in 2019 would have been the sum of the MVP/Transco path loss and the Transco alone path loss – a loss of [redacted]

Q. By stating that DESC not be allowed full recovery of its MVP and Transco SET contracts' costs, what would you recommend the Commission do?

A. My analysis leads me to conclude that either these costs should be disallowed altogether, or that any recovery be capped so that DESC's ratepayers are no worse than if the contracts hadn't been entered. In other words, the Commission should allow DESC to keep the savings, but also to bear the losses associated with these contracts.

Q. How would you measure these "savings" and "losses"?

A. The Commission would compare the costs of gas as delivered to DECGT or Elba respectively[18] under these projects' contracts with posted index prices for Transco Zone 5 South. Then, to the extent the delivered unit cost of gas through these contracts is less than the Transco Zone 5 South posted prices for delivered gas, DESC keeps this difference. This would allow DESC to offset the fixed reservation costs it is incurring but that ratepayers ***<u>are not</u>*** reimbursing. Conversely, to the extent the delivered cost of DESC gas through these contracts is *greater* than the Transco Zone 5 South posted prices for delivered gas, ratepayers only reimburse unit costs at the Transco Zone 5 South posted costs (*i.e.*, unit prices).

Q. What if DESC winds up retaining "savings" that exceed its costs, including the reservation costs of these contracts?

A. The Commission could decide to implement a shareholder/ratepayer sharing mechanism. DESC would presumably want to recover any previously un-reimbursed costs plus interest prior to sharing; but again, that would be up to the Commission.

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[18] These costs would be comprised of the cost of gas, plus (a) the variable cost of transportation (*i.e.*, the usage rate) to get the gas all the way to DECGT or Elba; and, (b) the cost of "fuel retainage" by the pipelines under the contracts (which is gas taken by the pipeline (*i.e.*, purchased by DESC) but not delivered to DESC because it is used to fuel compressors along the way.

Q. With respect to [redacted] **does this change your recommendation to this Commission?**

Q. A. No. [redacted]

Q. Because none of the costs of the two precedent agreements are in this case and your recommendations 1 & 2 relate to potential future costs, what do you recommend the Commission do at this time?

A. I strongly recommend that the Commission put DESC on notice that to the extent new contractual commitments increase costs above levels that would not be incurred but for those contractual commitments, and absent clearly evidenced cost-effective, reliability benefits, DESC will bear a heavy burden to recover such costs. This is fair to the Company as it provides time to find other parties to which it can release that capacity so that neither South Carolina ratepayers nor the Company shareholder absorb these costs. If DESC were to permanently release [redacted] In that case, DESC's exposure would be much less. In addition, should the Company find a party to which it can permanently release the other capacity, that too could reduce the Company's exposure to potentially unrecoverable costs.

Q. Does that conclude your testimony?

A. It does.

EXHIBIT GML-1

SkippingStone

Greg Lander, President
Skipping Stone LLC

Professional Summary:

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

Professional Accomplishments:

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser’s business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.

- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial &Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.

- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser’s business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in “pipeline alley”, developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.

- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.
- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Expert witness in numerous gas and electric utility rate cases; integrated resource plans; litigated service offerings and cost approval and allocation proceedings for public interest clients. Controversies, often involving hundreds of millions to billions of dollars over cases' time horizons, are common.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates,

costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.

- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).
- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Designed pipeline capacity release deal integrating settlement system for firm users, including design and development for information services delivery on a transaction fee basis.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed "universal capacity contract" data model for storage of all interstate capacity contract transactions from all 60 major interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).

- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC's Acting Manager, was responsible for developing business case and economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open Season, as well as assisted with prospective shipper negotiations. Project cancelled due to 2001 "California Energy Crisis" and contemporaneous Enron and energy trading sector implosions.
- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm precedent, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfields pipeline and expansion of storage system.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients' attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, and supply contract proceedings as both up-front and behind the scenes expert.

<u>Associations and Affiliations:</u>

Longest serving Member of Board of Directors for NAESB and prior to that GISB - 23 years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee.

Past and Affiliations and Associated Accomplishments:

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

Education:

1977: Hampshire College, Amherst, MA; Bachelor of Arts

Publication:

2013: Synchronizing Gas & Power Markets - Solutions White Paper

Exhibit GML-1: Expert Testimony of Gregory M. Lander

Name of Case	Jurisdiction	Docket Number	Date
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP04-251-000	May 3, 2004 (Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP08-426-000	May 19, 2009 (Answering Testimony) June 2, 2010 (Supplemental Answering Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP10-1398-000	June 28, 2011 (Answering Testimony) March 4, 2014 (Answering Testimony)
Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid for Approval by the Department of Public Utilities for a Firm Transportation Contract with Algonquin Gas Transmission Company	Massachusetts Department of Public Utilities	13-157	December 12, 2013 (Direct Testimony)
Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate	Massachusetts Department of Public Utilities	15-34	June 5, 2015 (Direct Testimony)

pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project			
Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project	Massachusetts Department of Public Utilities	15-39	June 5, 2015 (Direct Testimony)
Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A	Massachusetts Department of Public Utilities	15-48	June 5, 2015 (Direct Testimony)
Investigation of Parameters for Exercising Authority Pursuant to Maine Energy Cost Reduction Act, 35-A M.R.S.A. Section 1901	Maine Public Utilities Commission	2014-00071	July 11, 2014 (Direct Testimony)
Virginia Electric and Power Company’s Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2017-00051	August 11, 2017 (Direct Testimony)

In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas Service In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service	Missouri Public Service Commission	**File No. GR-2017-0215** **File No. GR-2017-0216**	September 8, 2017 (Direct Testimony) Consolidated and November 21, 2017 (Surrebuttal Testimony) Consolidated
Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019. Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	California Public Utilities Commission	Application 17-10-007 Application 17-10-008	Consolidated Direct Testimony May 14, 2018 Rebuttal Testimony June 8, 2018
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia	Virginia State Corporation Commission	PUR-2018-00067	Direct Testimony June 14, 2018
Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process	California Public Utilities Commission	Application 17-10-002	Direct Testimony July 2, 2018
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2018-00065	August 13, 2018 (Direct Testimony)

In the Matter of Constellation Mystic Power, LLC Docket No. ER18-1639	Federal Energy Regulatory Commission	ER18-1639	September 4, 2018 (Cross Answering Testimony)
South Carolina Electric and Gas Company Application for Approval of Merger with Dominion Resources Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E	South Carolina Public Service Commission	Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E	September 24, 2018 (Direct Testimony)
In re: Annual Review of Base Rates for Fuel Costs of South Carolina Electric and Gas Company	South Carolina Public Service Commission	Docket 2019-2-E	March 19, 2019 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service	New York Public Service Commission	Case 19-G-0066	May 24, 2019 (Direct Testimony)
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to VA Code § 56-249.6.	Virginia State Corporation Commission	Case No. PUR-2019-00070	June 19, 2019 (Direct Testimony)
In the Matter of Annual Review of Base Rates for Fuel Costs for Duke Energy Carolinas, LLC, Increasing Residential and Non-Residential Rates	South Carolina Public Service Commission	Docket 2019-3-E	August 19, 2019 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service	New York Public Service Commission	Case-19-0309	August 30, 2019 (Direct Testimony)
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The KeySpan Gas East Corp. d/b/a National Grid for Gas Service	New York Public Service Commission	Case-19-0310	August 30, 2019 (Direct Testimony)